Memorandum

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Telephone: ATSS ( ) (916) 653-0159

To: Commissioner Robert A. Laurie
Commissioner David A. Rohy

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From: California Energy Commission - Marc Pryor
1516 Ninth Street Project Manager
Sacramento, CA 95814-5512

Subject: **Supplemental Testimony to the La Paloma Generating Project (98-AFC-2) Final Staff Assessment**

On April 7, 1999, the California Energy Commission (Energy Commission) staff filed its Final Staff Assessment (FSA) for the La Paloma Generating Project, a 1,048 megawatt natural gas-fired power plant to be located in western Kern County, California. As noted in the FSA, the air quality, biological resources, water resources, paleontological resources and cultural resources technical areas were incomplete due to a lack of timely information.

Attached is the revised testimony for the soil and water resources technical area.

SUMMARY OF THE REVISED DOCUMENTS

Soil and Water Resources

Staff has addressed the following: 1) an analysis of the project's conformity with the State Water Regional Control Board (SWRCB) Policy 75-58; 2) the Class I injection well permit from the Environmental Protection Agency (anticipated in August, 1999); 3) agreements between the California Department of Water Resources, West Kern Water District and the Kern County Water Agency have not been completed regarding the proposed turnout on the California Aqueduct; and 4) an agreement between these agencies regarding West Kern Water District's ability to place groundwater into the aqueduct to meet any shortfalls in State Water Project deliveries has also not been completed.

Attachment

cc: Proof of Service

SOIL AND WATER RESOURCES

Supplemental Testimony of Joseph O'Hagan

INTRODUCTION

In the Final Staff Assessment (FSA), staff stated that they did not have sufficient information to reach a conclusion about the proposed project's compliance with State Water Resources Control Board's (SWRCB) Policy on the Use and Disposal of Inland Waters Used for Power Plant Cooling. This supplemental testimony will provide staff's conclusions about the project's compliance with this policy as well as a brief discussion of wastewater disposal options other than the use of injection wells.

ALTERNATIVE WATER SOURCES AND COOLING TECHNOLOGY

As discussed in the FSA, LPGP proposes to use State Water Project water from a new turn out on the California Aqueduct. This water will be from the West Kern Water District (WKWD) which is entitled to 25,000 acre feet of SWP water per year through a contract with the Kern County Water Agency.

Assuming average operating conditions over the course of a year, La Paloma estimates that the project, assuming a 93 percent capacity factor, will require 5,530 acre-feet of water (LPGP, 1998a). Assuming maximum operating conditions over the course of a year, La Paloma estimates that the project, assuming a 100 percent capacity factor, the project will require approximately 6,000 acre-feet. Service of the proposed project does not represent a new water right or a new diversion of State Water Project water. WKWD historically has diverted as much State Water Project water as possible, most of which has been banked through the exchange program with Buena Vista Water Storage District. See Soil & Water Resources Table 1 in the FSA regarding WKWD water supply, demand and storage. Therefore, use of this water by LPGP is not a new diversion, merely a change in use of an existing diversion.

The SWRCB's Policy on the Use and Disposal of Inland Waters Used for Power Plant Cooling, adopted by resolution 75-58, states that use of fresh inland waters should only be used for power plant cooling if other sources or other methods of cooling would be environmentally undesirable or economically unsound. The policy provides that power plant cooling water should, in order of priority, come from wastewater being discharged to the ocean, ocean water, brackish water from natural sources or irrigation return flow, inland waste waters of low total dissolved solids, and other inland waters.

Staff's evaluation of the proposed project's compliance with this policy centered on the availability of produced water from oil wells, and groundwater from the Chevron U.S.A. Production Company (Chevron), and the use of alternative cooling technology. In response to a staff request for information, Chevron (Sirgo 1999) indicated that both produced and groundwater may be available for use by the LPGP. Produced water from Chevron's wells is available at the oil company's central processing facility, located approximately six miles northwest of the proposed power plant site. The volume of the produced water is estimated to be approximately 0.375 to 0.6 million gallons per day (Sirgo 1999). The total dissolved solids (TDS) level of the produced water is identified by Chevron as 6,200 mg/l and for the groundwater as 3,191 mg/l.

Chevron also indicated that groundwater in volumes between 0.63 and 1.0 million gallons per day would be available from an area approximately two miles north of the power plant site. In comparison, the LPGP proposes to use, on average, 7.64 million gallons per day of State Water Project (SWP) water, the majority of this for cooling tower makeup. Clearly, a combination of both produced and groundwater from these Chevron sources would be inadequate to meet LPGP's water requirements unless the size, and the corresponding water demand of the proposed project, is substantially reduced, or an alternative cooling technology like dry cooling is used. Furthermore, the high TDS levels of these two water sources would require treatment and, likely could only be used for several cycles through the cooling process.

In comparison, LPGP intends to cycle the higher quality SWP water ten times. Short of significantly reducing the size of the proposed project, a significant amount of SWP water or some other water supply would still be required for power plant cooling. Use of these sources would not replace the need for construction of the aqueduct turnout and associated pipeline, but would require the construction of additional pipelines. Therefore, staff sees that the use of Chevron's produced and groundwater sources provide, at best, only a small reduction in the amount of SWP water required for the project.

Potential environmental impacts associated with groundwater pumping and construction of the new pipelines could easily out weight the benefits of the slight reduction in SWP water use. On the other hand, use of these sources would involve an economic penalty on the project in regards to the costs of securing the use of these water sources, construction the pipelines and treatment of the water prior to use.

The SWRCB policy also requires that the use of dry and wet/dry cooling be evaluated. Staff provided a brief discussion of these cooling technologies in the FSA. Dry or wet/dry cooling clearly present a substantial environmental benefit in that they can represent a reduction in project water demand of up to 95 percent. These cooling technologies also represent a substantial cost above that required for conventional wet cooling towers. For the High Desert Power Project (97-AFC-1), the applicant (HDPP 1998) estimated that the initial capital costs of a wet/dry hybrid cooling system would be two times, and a dry cooling system would be more than two and one-half times the cost of the proposed wet system. For the San Francisco Energy Project, it was estimated that dry cooling towers would cost 2 to 3 times as much as the proposed hybrid cooling system. For the Sutter Power Project (1998) it was estimated that initial capital costs for dry cooling would be approximately $14 million more than a wet cooling facility. These estimates are consistent with information staff has received from cooling tower vendors. In general, the initial cost differences are due to the need for a dry condenser, or heat exchanger; taller structures for the cooling system and larger fans and motors.

Operating costs for dry and wet/dry cooling systems are also significantly higher. These alternative cooling systems are less efficient in rejecting heat, and generally have higher parasitic (fan) electrical loads and can create a higher pressure (temperature) in the steam turbine condenser. Both of these factors decrease the thermal efficiency and power output of the plant. Estimating the nature of this penalty is difficult given that the facility could be designed and operated in a variety of ways using one of these alternative cooling technologies. HDPP (1998) estimated that the costs of these alternative cooling technologies, compared to wet cooling would increase the cost of electricity 2.8 percent for a wet/dry cooling process to 4.9 percent for a dry cooling process. These figures are based upon estimated increases in fuel costs, capacity loss and capital expenditures in comparison to reduced water costs (CURE 1999).

Other factors, such as cost of mitigation measures required for impacts associated with water supply and wastewater disposal may reduce the costs of using one of these technologies for a project. For the Sutter Power Project (1998), the applicant estimated that using a dry cooling and zero discharge (see below) system will reduce the facilities output and efficiency between 1.5 and 5.0 percent. Initial estimates for the Sutter Power Project that only addressed fuel costs, capital expenditures and capacity losses, indicated that dry cooling would cost the project over $69 million more than using wet cooling. A latter estimate by the Sutter Power Project concluded that, factoring in mitigation costs, dry cooling would cost the project an addition $25 million over the life of the project. This reduction in the cost estimate is, at least in part, that the Sutter Power Project faced significant costs for mitigating water supply and disposal issues. It should also be noted that the proposed High Desert Power Project is 720 MW and the Sutter Power Project is 485 MW as compared to the 1,048 MW for the LPGP. Clearly, use of these alternative cooling technologies are feasible, but involve an increased cost to the proposed project. Staff is not able to evaluate the economics of the proposed project and is therefore, unable to determine the significance of these costs to the project.

Although there does not appear to be a clear environmental benefit to using the produced or groundwater for the project, there are some environmental benefits to using dry cooling. These environmental benefits involve removing the need for construction and operation of the aqueduct turnout, storage tank, pipelines and, potentially, the injection wells required because of the LPGP’s demand for cooling water. It is possible that the potable water from WKWD would be sufficient to supply water for the steam cycle. The poor quality of the groundwater and produced water from Chevron is unsuitable for this use. Environmental benefits from selecting the wet/dry hybrid cooling technology are unclear because it is uncertain how much water would still be required for the cooling water makeup. The aqueduct turnout, associated pipelines and storage facilities may still be required.

As noted above, the proposed use of groundwater and produced water from Chevron does not represent an environmental benefit. While dry cooling clearly represent an environmental benefit, it potentially represents a substantial cost to the project. Although it is technologically feasible, the full economic costs of operating a facility with dry cooling technology in western Kern County are not known to staff. Although the Sutter Power Project will utilize dry cooling, the setting and power plant economics are different.

While compliance with SWRCB Policy on the Use and Disposal of Inland Waters Used for Power Plant Cooling is a factor staff evaluates in its own right, other project specific factors should be taken into account. These factors, such as water supply impacts, vary with each project and must be evaluated on a case-by-case basis.

As noted above, the project water supply does not represent a new diversion of the SWP. Furthermore, project water demand will not adversely impact the WKWD. Nor does it appear that the water supply facilities proposed by LPGP will cause a significant impact to other resources. Taking these factors into account and the fact that alternative sources of water are not available, and that alternative cooling technology, although feasible, could be a major economic burden on the project, staff concludes that the proposed LPGP complies with the SWRCB Policy on the Use and Disposal of Inland Waters Used for Power Plant Cooling.

WASTEWATER DISPOSAL

LPGP has identified in the FSA the use of injection wells to dispose of wastewater. LPGP has applied to the U.S. Environmental Protection Agency (EPA) for a Class I Underground Injection Control Permit. EPA has deemed the permit application complete and it is anticipated that the permit will be issued by August, 1999. LPGP (1998a) did identify a zero discharge facility as an alternative method of wastewater disposal, although the preferred method of wastewater disposal is clearly the use of injection wells. LPGP did not provide any additional information about such a facility, nor did staff request such information.

Since the EPA permit will not be issued prior to the evidentiary hearing on water, this testimony will briefly discuss zero discharge technology. Zero discharge technology, refers to wastewater disposal options that don’t involve the release of wastewater to land or surface or groundwater. Zero discharge options include the use of evaporation ponds or such facilities as crystallizers. A crystallizer evaporates off the water from a wastewater stream leaving a solid waste consisting of the inorganic constituents of the wastewater stream. Condensing the water vapor produces a high quality water that can be re-used in the power plant. Since LPGP has not identified using zero discharge technology as the preferred method of wastewater disposal, nor has staff evaluated zero discharge technology, the use of any method other than the use of injection wells will require an amendment to the project.

REFERENCES

California Unions for Reliable Energy (CURE). 1999. Preliminary Dry Cooling Analysis for High Desert Power Project (97-AFC-1). Submitted to the California Energy Commission on March 30.

High Desert Power Project (HDPP). 1998. High Desert Power Project Response to California Energy Commission Staff Data Request Number 24. Submitted to the California Energy Commission (revision) March 8.

La Paloma Generating Project (LPGP). 1998. Application for Certification for the La Paloma Generating Project. Submitted to the California Energy Commission on July 10.

Sirgo, Eric. 1999. Letter to Robert L. Therkelen (sic) California Energy Commission, regarding the request for source water for the La Paloma Generating Project on April 3.

Sutter Power Project (97-AFC-2). 1998. Application for Certification Mitigation Program Supplement. Submitted to the California Energy Commission in October

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